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Optimal power market timing for wind energy

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ABSTRACT

The key parameters of current power markets are adjusted to match a system dominated by different thermal generation technologies. This could be revised with an increasing share of fluctuating renewable energy sources. Namely timing issues can pose a discriminatory framework to different technologies in the market. This paper provides a conceptual analysis of different timing options for the electricity spot market and a quantitative study regarding the discussed effects. The most prominent timing option being discussed is the gate-closure horizon. In the day-ahead market, bids have to be submitted until gate-closure time. The time span between gate closure and delivery is the gate-closure horizon and gives market participants time for creating their dispatch schedules. Contrarily, it is a source of balancing costs for wind energy operators because the forecast error increases with the gate-closure horizon. Therefore, the longer the gate-closure horizon is, the higher is the risk for the wind energy operator to be imbalanced. Depending on the combination of thermal and renewable generation in the system, an optimal gate closure horizon can be determined. A hitherto neglected timing factor is the trading period length. Currently, this covers all 24 hours of the following day. By keeping current gate closure time, but shortening the trading period length, the required prognosis horizon for wind power can be shortened – and forecasting errors can be minimised. This implies that auctions for several time spans of the following day are held successively. Again, shortening this for the benefit of fluctuating renewable energy can be detrimental for inter-temporally constrained operators (i.e. thermal plants, demand response) because they need to optimise their operation over a number of hours. A third option is keeping both the gate-closure horizon and the trading period length constant, but moving the whole process to a different daytime. The analysis shows that this can be beneficial if balancing power prices are mainly dependent on thermal generation and demand variations However, it can lead to adjustment costs for market participants. The key result is that optimised day-ahead market timing improves the interplay of fluctuating wind energy and thermal technologies. In quantitative terms, the presented options depend strongly on the technological combination in the market considered. The authors conclude that timing options are crucial in designing markets such that both the volatility of intermittent wind production and the inter-temporal constraints are efficiently coordinated.

1 INTRODUCTION

Today’s power market design with day-ahead spot market auctions, successive intraday auctions and final balancing and regulating of remaining deviations has been developed chiefly for existing structures. In 1971, the predecessor of Nord Pool Spot was launched as a system to optimise the dispatch of hydro reservoirs in Norway. Assuring electricity system stability calls for ahead-planning and dispatch instead of real-time markets. Day-ahead planning – i.e. the unit commitment and dispatch planning the day before delivery – evolved traditionally for practical reasons as it is in line with the daily pattern of decision makers. After the liberalisation of Europe’s national electricity markets around the turn of the century, competitive national day-ahead markets were established in a first step. Successive developments, though at a different pace in different countries, are national intraday markets and the harmonisation of markets, especially market mechanisms and timing, across borders. Using the electricity exchange for trading is not mandatory, which is why their product design has to be

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beneficial for market actors in comparison to bilateral over-the-counter trading. The single exchanges are either owned by a number of electricity market actors or by financial institutions like commodity exchanges. They are primarily regulated by supervisory bodies for financial institutions and abide to general commodity exchange rules, whereas their product range, design and fees are at their discretion (though influenced by regulator's positions). In practice, this leads to a product portfolio that is based on well-established historical products and new ones that are designed in cooperation with market actors and energy regulators. The probably most important development for the integration of wind energy in power markets during the last years is shortening the gate closure on intraday markets. This allows for correcting prediction errors until very shortly before delivery without being exposed to the higher imbalance charges (see e.g. Holttinen, 2005, for an in-depth analysis of the value of intraday markets for wind power, or Weber (2009) on existing intraday markets).

To the authors' knowledge, the impact of general power market design on achieving EU goals for sustainable energy – such as a 20% generation share by 2020 – is a hitherto underestimated research field. Latest works comprise Meeus (2010), dealing with power exchange incentive structures, and Neuhoff et al. (2011a) as well as Neuhoff et al. (2011b), which focus on transmission capacity allocation and pricing for the efficient integration of RES-E. An ongoing EU-funded project is OPTIMATE, where a model of the West European electricity sector will be able to reflect changes in electricity market design (www.optimate-project.eu). When selling wind energy in liberalised power markets, actors face the choice between a) selling it day-ahead and correcting deviations in intraday markets or b) selling it directly in intraday markets when the prediction error is lower. Option a) is compulsory in some countries, e.g. in Germany for all the wind power receiving the feed-in support scheme. Accepting the day-ahead market as the main and most liquid market, both options lead to suboptimal unit commitment and dispatch planning that comes at a cost for the overall system. In case a), this is aggravated by additional transaction costs. With the increasing share of electricity from renewable energy sources (RES-E), the importance of a power market design that is reflecting the needs of fluctuating resources while ensuring overall system reliability is increasing. This paper analyses different timing options of the main ahead market (which is not called the day-ahead market in the following because this term represents the existing benchmark situation).

The remainder of the paper is structured as follows: first, the different possible concepts of modifying the timing of the main ahead market are described. They cover a later gate closure time, a shorter main market period length (i.e. shortening the reference period from 24 to e.g. 12 hours) and shifting the whole trading process by some hours. Notably, the presented options do not cover longer planning horizons as an option. It is assumed that only a system with shorter timing, reflecting a more flexible system with a larger share of fluctuating RES-E, possibly offers improvements. Second, the quantitative model for the assessment of the different options is addressed. Third, the results are presented, before turning to the final discussion and conclusions.

2 CONCEPTS – TIMING OPTIONS

This section is partially based on the report on "Innovative target market designs" of the OPTIMATE project (Weber/Schroeder, 2010).

Figure 1 gives a conceptual overview of the main time determinants in power markets. The illustration is based on the current status in most European power markets. Demand needs to be covered over one day, reaching from hours α to β (typically 1 to 24). This is the *trading period length*. The other main time determinant is the *gate-closure horizon*: it is the distance between final submission of all bids at the power exchange and the first hour of delivery. Another aspect illustrated in the figure is that forecast errors from variable RES-E generation (ΔRES-E) increase with time distance. For wind power, quantifications of this effect for wind power can be found in the literature review by Monteiro et al. (2009) or in Graeber et al. (2010).

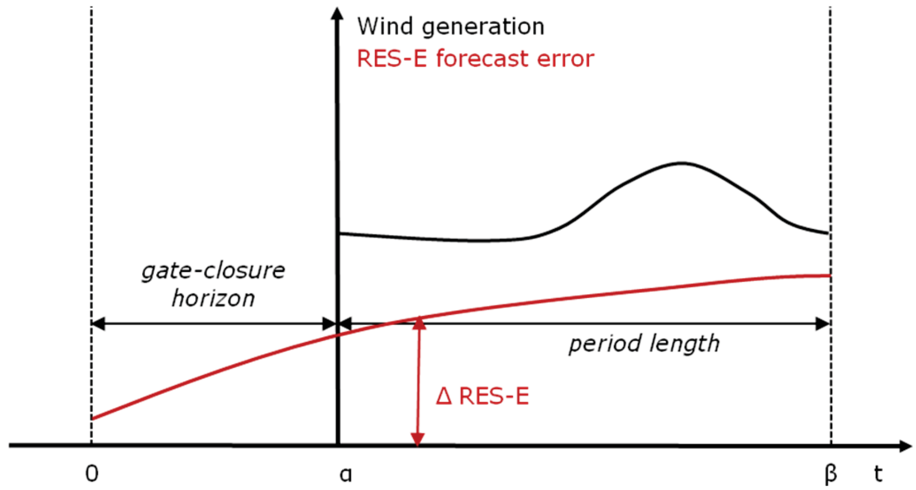

Figure 1: Time determinants in power markets

2.1 Changing the gate closure horizon

Figure 2 shows the effect of shortening the day-ahead gate-closure horizon. In practice, this corresponds to having the gate closure in the afternoon or evening hours instead of at noon. Our point in this context is that a shorter gate-closure horizon will decrease the consequences of forecast errors. With regard to wind energy, this argument has been discussed and quantified by Holttinen (2005). The introduction of intraday markets during the last years has certainly reduced this effect. Nevertheless, all intraday corrections are associated with transaction costs and possibly other market imperfections (Weber/Schroeder, forthcoming). Changing the gate-closure horizon remains therefore a reasonable measure to consider. Obviously, this has an impact on power plant operator's planning, as a shorter gate-closure horizon might have a negative impact on unit commitment and dispatch decisions if the power system covers slowly reacting units. Additionally, the costs of keeping a unit in standby mode from the end of a trading day until the following gate closure could increase.

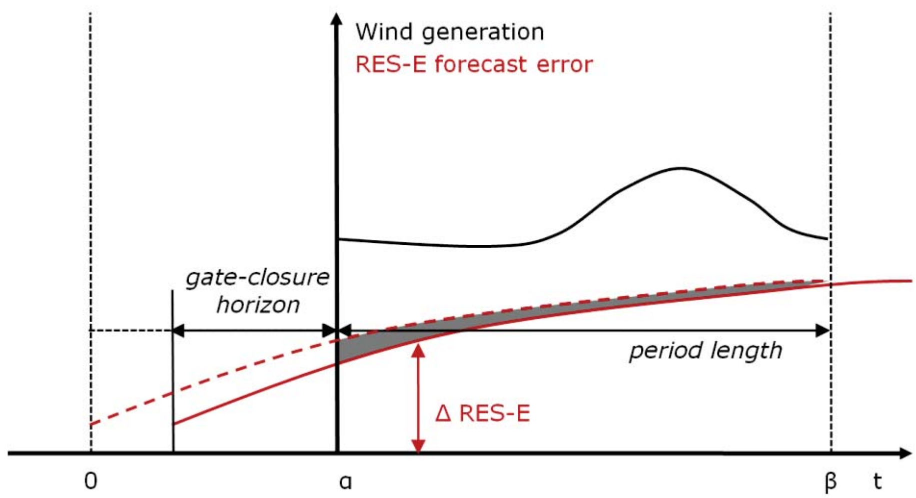

Figure 2: Time determinants in power markets - Changing the gate-closure horizon

2.2 Changing the trading period length

Another proposed measure is the shortening of the trading period length, as illustrated in Figure 3. In the graphical example, the trading period length is cut in half (12 hours). Keeping a gate-closure horizon of e.g. 12

hours, this means that at 12am, the 12 hours from 12pm are scheduled and vice versa. In comparison to the base case, where the period reaching from 12 to 36 hours ahead is computed, this offers the advantage that forecast tools only need to provide reliable results for a shorter time horizon. Instead of 36 hours, the maximum look-ahead time is now reduced to 24 hours. This in turn leads to a lower adjustment requirement due to the shortened look-ahead time as sketched in the figure. For slowly reacting thermal units, the unit commitment decision could be impacted because startup decisions are based on a shorter period length. The magnitude of this effect depends on the unit commitment and dispatch assumptions for the thermal units in the system.

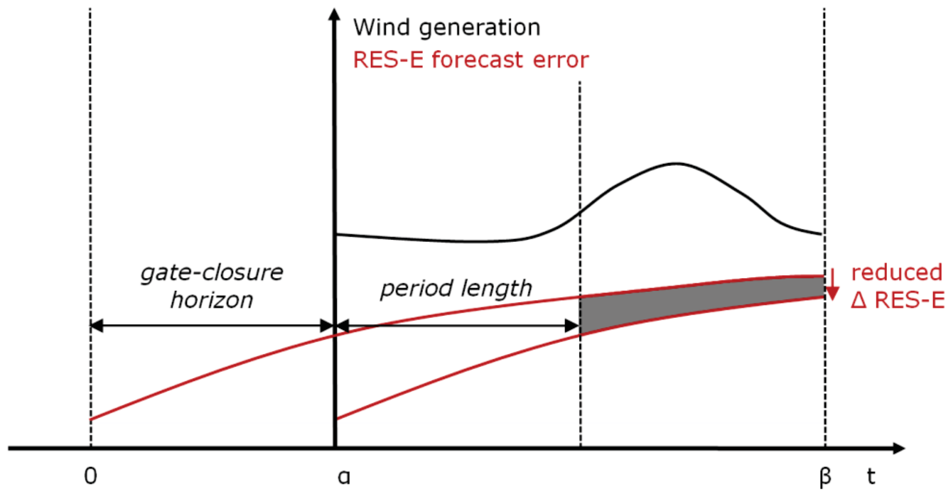

Figure 3: Time determinants in power markets - Changing the trading period length

2.3 Shifting the trading period

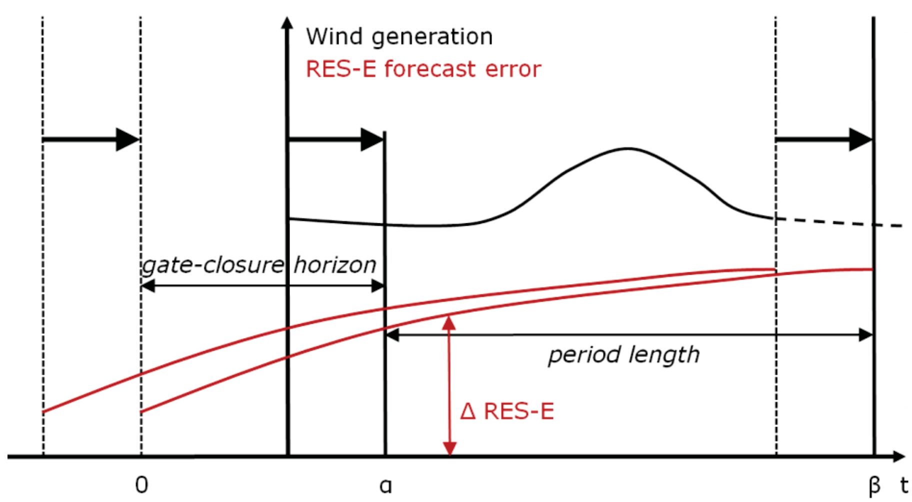

Figure 4: Shifting the trading period

Figure 4 is a more complex picture than the previous ones. Instead of shortening the gate-closure horizon or trading period length, these two are merely moved. As an example, a trading period length could reach from 6am to 6am, instead of being identical with calendar days. The gate-closure time could be moved analogically, e.g. from 12pm to 6pm. The effect is primarily similar to shortening the gate-closure horizon: the daily peak of wind generation and the associated forecast error are moved closer to the gate closure. In return, hours with less wind production – and therefore an overall lower forecast error – are moved to the end of the period length. For these reasons, moving the whole trading process could be advantageous for RES-E: the financial consequences of adjusting forecast errors are reduced because the whole period is moved. Unit commitment and dispatch decisions of non-fluctuating units remain as they are today; the trading process is merely shifted by a few hours.

3 MODEL

3.1 Assumptions

In contrast to the common assumption of perfect markets, we assume that intraday markets cannot capture all corrections in a cost-neutral way. This leads to the ambition that the main market should be able to match RES-E and thermal generation in a least-cost way from a system point of view. Following intraday corrections are cheaper than paying ex-post balancing fees, but still associated with flexibility costs.

Wolak (2007) argues that it is beneficial to have ahead-markets instead of real-time markets only. The reason is the possible exercise of market power by provoking scarcity rents. If several market participants commit to delivieries in an ahead-market, this possibility is reduced. Together with the fact that today's West European markets enjoy a certain trust among their participants, this paper only regards changes in timing. Changes in the general structure of an ahead-auction with a following intraday market are not discussed in this paper.

The principle of participating voluntarily on electricity exchanges, in contrast to pools, makes it desirable to have an attractive market design for all market participants. This comprises financial actors that improve the liquidity especially in intraday markets. In most European power markets, more electricity is traded via bilateral over-the-counter trades than via power exchanges. Therefore, we assume that transaction costs of market participants due to adjusting to a changed timing structure are limited as they could switch to bilateral contracts.

Flexibility costs are defined as Transaction costs + Costs of inefficient unit commitment. The reference case for flexibility costs is defined as a gate closure horizon of 12 hours and a period length of 24 hours. If everything (including demand, outages, etc.) was perfectly known in advance, flexibility costs would not play a role. If, however, new information arrives over time, this may lead to a certain demand for flexibility. Then, it is critical to efficiently reconcile the demand for that flexibility with the limited, costly flexibility of the thermal production environment.

For the case of electricity production from wind, the forecast error rises proportionally with power production. In the short term, this argumentation is doubtful due to the shape of the typical power curve of a wind turbine. In the long run and working with averaged or aggregated data, it is a valid approximation.

All changes to the time structure should be based on full hours and such that an overall daily pattern can be kept. In other words, if the period length is shortened to t hours, t*N is equal to 24.

The power market timing should be optimal in the long run. This criterion excludes the possibility of seasonal adjustments to the power market design due to seasonally different variations in RES-E generation.

Finally, it is assumed that meteorological updates and related power production forecasts are updated on an hourly basis. All wind power generation is bid into the ahead-market and errors are corrected afterwards at the respective flexibility costs.

3.2 Data

The following analyses are based on specific set of data and associated assumptions. The daily wind production profile corresponds to the average, normalised profile in West Denmark over a period covering several years. The forecast error (N-RMSE) over time is displayed in Figure 5 and based on the current forecast quality used at EnBW TSO. The error is given as normalized root mean square error (N-RMSE, also R-RMSE for 'relative'). The N-RMSE is defined as the root of the average, squared absolute forecast errors divided by the total generation capacity. The other graphs in the figure display examples of flexibility costs in different power systems. If information is known correctly 37h ahead and enters today's day-ahead market, no flexibility costs are associated with it. For all adjustments closer to real time, flexibility costs apply. Five different examples of flexibility costs are assumed: an inflexible system system with high or low costs. The term inflexible describes the property that costs are increasing towards real-time over the whole regarded period. This reflects possible inefficiencies due to wrong unit commitment and dispatch of large thermal units. By contrast, the flexible systems with high or low costs exhibit rising flexibility costs only before the last few hours before real-time. The fifth system is a fully flexible system where flexibility costs are constant and equal to transaction costs over all hours. In practice, a 100% hydro reservoir system corresponds to this concept. Flexibility costs of existing power systems are hard to determine and depend strongly on decision-making process assumptions. The five cases constitute illustrative examples. Newly erected and planned thermal units have far faster startup and modulation characteristics than their predecessor generation. Additionally, coal and nuclear units tend to be replaced with gas-fired power plants which are more flexible. These developments correspond to the change from an inflexible to a flexible system in our concept.

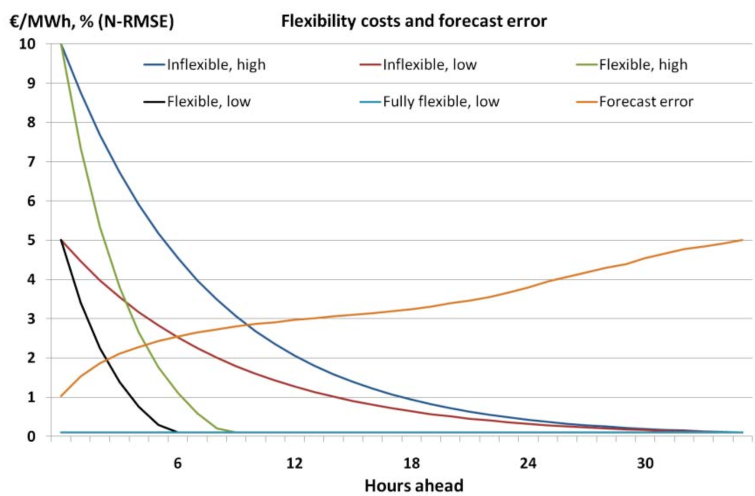

Figure 5: Flexibility costs of different scenarios and forecast error

3.3 The pricing of forecast errors

The starting point of the model is that 1 MWh of forecast error in the benchmark case (12h of gate closure horizon, 24h period length) needs to be corrected. This happens with the improved forecast over time. Thus, about 80% of the forecast error can be corrected until one hour before delivery. Let *a* be the forecast horizon, i.e. hours to delivery. The share traded *h* hours ahead is identical for all hours of the gate-closure horizon. The underlying idea for this is that the forecast error that can be precised *a* hours ahead is constant – the error that can be corrected e.g. 1 hour ahead is indifferent of the market design. For the hours beyond the gate-closure horizon, the amount to be corrected (Q_{corr}) equals

$Q_{corr}(h) = [FE(h-1) – FE(h)]* HW(h)$,

where FE denominates the forecast error at different times and HW is the normalised hourly wind generation of the reference hour. HW is the hourly wind generation of the reference hour: assume that hour no. 1 of a day is 8.9% below the average daily production, whereas hour no. 13 is about 14.4% above the average daily production. Following this argumentation, the forecast errors that can be corrected 13 or 25 hours ahead, respectively, vary by these factors. In a second step, these hourly amounts to be corrected are multiplied with the flexibility costs (FC(h)) of the different scenarios and set in relation to the benchmark case. This yields the resulting savings for wind power generation:

$$Savings = \frac{\sum_{h=0}^{\beta} Q_{corr}(h) * FC(h)}{\sum_{h=0}^{\beta=36} Q_{corr,benchmark}(h) * FC(h)}$$

This model is applied to the different concepts described above. Results are described in the following.

4 RESULTS

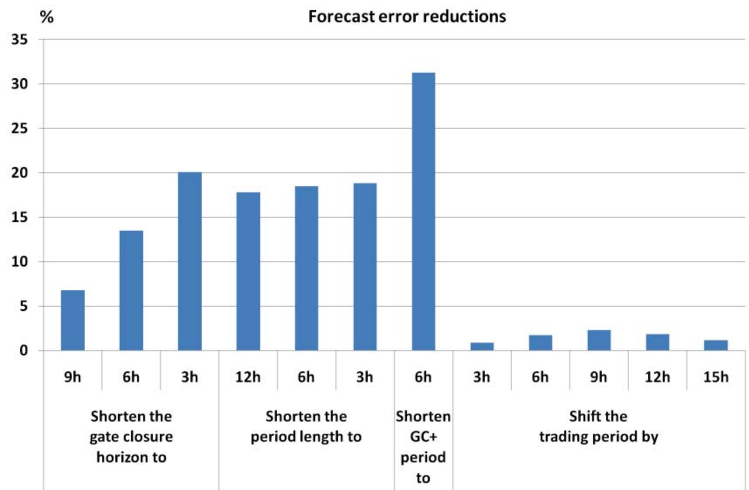

Figure 6: Forecast error reductions for different timing options

Figure 6 displays the forecast error reductions through market design changes in comparison to the benchmark case. Shortening the gate closure has a considerable effect. Due to the fact that a large share of forecast errors lie within the first hours, shortening the period length does not have such a pronounced effect: the forecast horizon is limited to 24 hours under a period length of 12 hours and to 18 hours under a period length of 6 hours. A special case is the combination of both options, i.e. shortening both the gate closure horizon and the period length to 6 hours. As a result, the maximum relevant forecast error corresponds to 12 hours ahead. This yields a reduction of more than 30%. In comparison, the benefits of shifting the trading period are small: the peak is at 2.3% for a shift by 9 hours.

Table 1 shows the savings that can be achieved due to changes in market design for the different assumed power systems and their associated flexibility costs. Shortening the gate closure horizon gives balancing cost reductions between 0.15 and 4.34% for all power systems except the fully flexible one. For the fully flexible system, the possible savings are identical to the physical amounts (forecast error reductions) discussed above. Shortening the period length leads to improvements that are roughly comparable to shortening the gate closure horizon to 6 hours. Notably, the differences between shortening the period length to 12 or 3 hours are quite small. An exemplary combination of both concepts, shortening the gate closure horizon and the trading period to 6 hours, corresponds to holding an auction every 6 hours for the period of 7-12 hours ahead. It leads to higher benefits in all cases, especially in an inflexible power system. Finally, shifts in the trading period result in improvements of about 0.2-0.3% in the inflexible power systems, 0.05-0.1% in the inflexible systems and 2.3% in the fully flexible system.

Table 1: Savings for wind energy balancing through changes in market timing in per cent (relative to benchmark case)

Power system, flexibility costs		Inflexible, high	Inflexible, low	Flexible, high	Flexible, low	Fully flexible, low
Shorten the gate closure horizon to	9h	0.67	0.90	0.15	0.32	6.77
	6h	1.72	2.21	0.32	0.63	13.47
	3h	3.56	4.34	0.75	0.99	20.09
Shorten the period length to	12h	1.49	2.09	0.39	0.84	17.81
	6h	1.43	2.04	0.41	0.87	18.49
	3h	1.51	2.14	0.41	0.89	18.85
Shorten gate closure + period to	6h	6.45	7.84	0.91	1.47	31.23
Shift the trading period by	3h	0.05	0.08	0.02	0.04	0.87
	6h	0.12	0.17	0.04	0.08	1.72
	9h	0.19	0.27	0.05	0.11	2.30
	12h	0.19	0.26	0.04	0.09	1.86
	15h	0.15	0.20	0.03	0.06	1.18

5 DISCUSSION

The results presented above illustrate that changes in market design could lead to reduced balancing costs for wind power. They are exclusively from a wind power perspective and calculated with an average production series from West Denmark. With the ongoing integration of European power markets, a common timing structure for all markets is required. For drawing conclusions about all Europe, it would therefore be appropriate to regard the daily wind generation patterns of all countries and compare it to regional flexibility costs. These depend on the remaining generation structure. The concept of flexibility costs used in this paper is hard to estimate from existing power markets with existing models. First, the existing market timing structure is a fundamental assumption in these models and hard to alter. Second, the results are depending on the assumptions made for unit commitment and dispatch. If large thermal units are for example defined as always running, changes to the gate closure horizon or period length will not have an effect on their unit commitment. If a large unit's commitment decision is made based on its long upstart time and a short-term power market, it might not operate and this decision could increase system costs. Let us assume that the current timing structure with a gate closure horizon of 12 hours and a period length of 24 hours is useful for the operation of existing thermal units. First, the share of RES-E – and their share of balancing cost of total system costs – is increasing and they are partially replacing existing units. Second, a number of the existing units is progressively replaced with faster-reacting gas-fired units. Third, new large-scale thermal units offer significantly faster startup and modulation characteristics (Schiffer 2010). This means that the value of the prevailing timing structure will decrease. In other words, this development starts out at an inflexible system with high flexibility costs. If unit commitment decisions for slowly reacting units and block bids over a number of hours still play a role in the changed system, it corresponds best to the inflexible system with low flexibility costs. If all units in the system can start and stop quickly with low costs, the flexible systems correspond best to the future situation. The fully flexible system can be described as a system of fluctuating RES-E and hydropower reservoir units only. Day-ahead market signals do not offer any major benefits for the market participants in this case, apart from daily optimisation of storage units as e.g. pumped hydropower. However, the basic assumption is that fluctuating RES-E units bid their expected generation into the ahead-power market and correct fluctuations afterwards. This assumption does not hold for the fully flexible system and for the time horizon of flexible systems where flexibility cost is identical to transaction cost. If there is no cost associated to bidding at a later point in time when the forecast error is lower, there is no reason to bid in ahead-markets. For this reason, the comparatively large benefits displayed in Table 1 for the fully flexible system would not materialise in reality.

6 CONCLUSIONS

This paper looks at a number of options to change the timing of the day-ahead market: shortening the gate closure horizon, shortening the trading period and shifting the existing market by a number of hours. If all wind power is sold in the ahead-market and needs to be corrected afterwards, the possible reductions are most distinct in the cases where the market length is reduced considerably. Such measures would however have serious impacts on the scheduling of thermal units.

The existing power markets are voluntary and well-functioning; all changes to them should only be done cautiously and after detailed analyses. Changing the gate closure horizon and/or the period length are major changes that are not suggested in the short run, but might be worth a more detailed analysis in the long run. Shifting the trading period could reduce the amount to be balanced by 2.3% by moving the daily wind power production peak closer to real-time. However, the financial consequences are limited to about 0.3% because the respective hours remain distant to gate closure. It is estimated that these numbers indicate the lower limit of possible savings for the power system, without regarding costs caused by shifted working hours on energy trading floors. In principle, the same argumentation applies to PV generation, where the variation between day and night is even stronger. Temperature-depending electricity demand might also be forecasted slightly better if the trading process is shifted by a few hours and therefore, gate closure and the daily demand peak get closer to each other.

Due to the large share of slowly reacting thermal units in Europe, it seems reasonable that the costs associated to shortening the gate closure horizon and/or the period length would exceed the discussed gains due to reduced balancing costs. This might change in the long run with an increasing share of fluctuating RES-E. In the short-term, shifting the trading period seems a more balanced option. Gains due to reduced balancing are very limited, but costs on the side of thermal units and their market processes are as well. The main costs associated would be to pay employees for working at different times of the day. Interactions with other relevant markets as e.g. daily routines of the gas market could also play a role. In conclusion, this paper presents novel options of ahead-market design modifications. In the long run, adapting the market design to the growing share of wind power and other fluctuating RES-E might be beneficial. In the short run, shifting the trading process and period by a number of hours is an option that seems worth for further analysis. This option should be seen independently from other discussed modifications, e.g. a later gate closure of intraday markets or reshaping price zones, which should not be neglected.

7 ACKNOWLEDGEMENTS

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